Environmental Control Devices
SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant
AirPol, Inc.

Additional Team Members
FLS miljo, Inc. (FLS)—technology owner
Tennessee Valley Authority—cofunder and site owner

Location
West Paducah, McCracken County, KY

Technology
FLS' Gas Suspension Absorption (GSA) system for flue gas desulfurization (FGD)

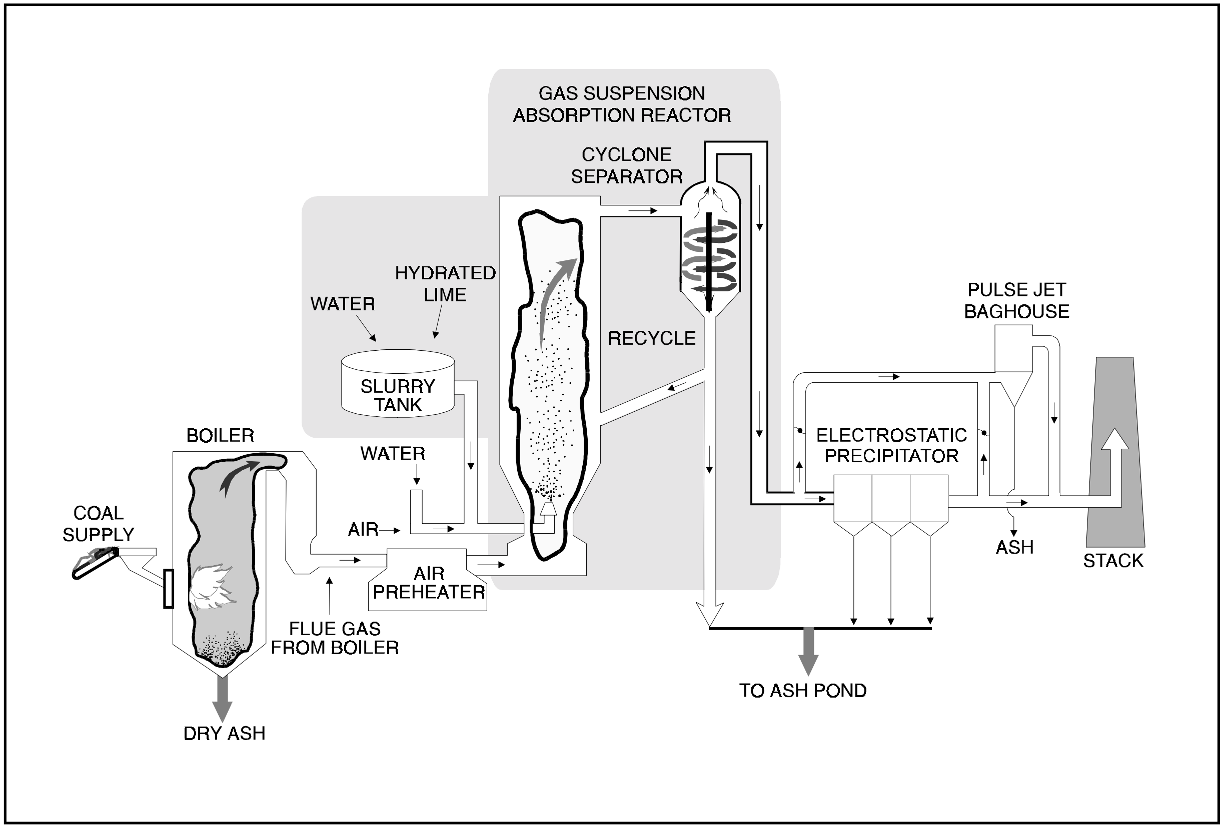
Plant Capacity/Production
10-MWe equivalent slipstream of flue gas from a 175-MWe wall-fired boiler

Coal
Western Kentucky bituminous—
Peabody Martwick, 3.05% sulfur
Emerald Energy, 2.61% sulfur
Andalax, 3.06% sulfur
Warrior Basin, 3.5% sulfur (used intermittently)

Project Funding

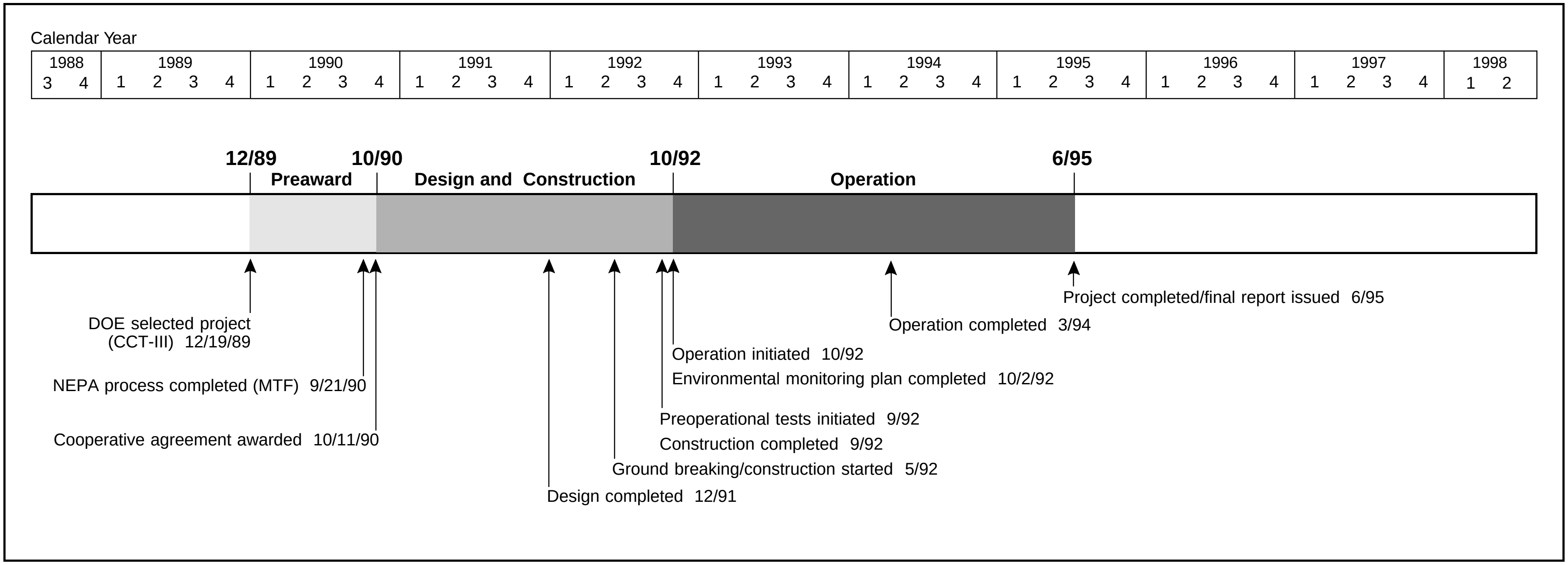
Total project cost	$7,717,189	100%
DOE	2,315,259	30
Participant	5,401,930	70

Project Objective
To demonstrate the applicability of Gas Suspension Absorption as an economic option for achieving Phase II CAAA SO_2 compliance on pulverized coal-fired boilers using high-sulfur coal.



Technology/Project Description
The GSA system consists of a vertical reactor in which flue gas comes into contact with suspended solids consisting of lime, reaction products, and fly ash.   About 99% of the solids are recycled to the reactor via a cyclone while the exit gas stream passes through an electrostatic precipitator (ESP) or pulse jet baghouse (PJBH) before being released to the atmosphere.   The lime slurry, prepared from hydrated lime, is injected through a spray nozzle at the bottom of the reactor.   The volume of lime slurry is regulated with a variable-speed pump controlled by the measurement of the acid content in the inlet and outlet gas streams.   The dilution water added to the lime slurry is controlled by on-line measurements of the flue gas exit temperature.

A test program was structured to (1) optimize design of the GSA reactor for reduction of SO_2 emissions from boilers using high-sulfur coal, and (2) evaluate the environmental control capability, economic potential, and mechanical performance of GSA. A statistically designed parametric (factorial) test plan was developed involving six variables. Beyond evaluation of the basic GSA unit to control SO_2, air toxics control tests were conducted, and the effectiveness of a GSA/ESP and GSA/PJBH to control both SO_2 and particulates were tested. Factorial tests were followed by continuous runs to verify consistency of performance over time.



Results Summary

Environmental

- Ca/S molar ratio had the greatest effect on SO_2 removal, with approach-to-saturation temperature next, followed closely by chloride content.
- GSA/ESP achieved
  – 90% sulfur capture at a Ca/S molar ratio of 1.3 with 8 ºF approach-to-saturation and 0.04% chloride,
  – 90% sulfur capture at a Ca/S molar ratio of 1.4 with 18 ºF approach-to-saturation and 0.12% chloride, and
  – 99.9+% average particulate removal efficiency.
- GSA/PJBH achieved
  – 96% sulfur capture at a Ca/S molar ratio of 1.4 with 18 ºF approach-to-saturation and 0.12% chloride,
  – 3–5% increase in SO_2 reduction relative to GSA/ESP, and
  – 99.99+% average particulate removal efficiency.
- GSA/ESP and GSA/PJBH removed 98% of the hydrogen chloride (HCl), 96% of the hydrogen fluoride (HF), and 99% on more of most trace metals, except cadmium, antimony, mercury, and selenium. (GSA/PJBH removed 99+% of the selenium.)
- The solid by-product was usable as low-grade cement.

Operational

- GSA/ESP lime utilization averaged 66.1% and GSA/PJBH averaged 70.5%.
- The reactor achieved the same performance as a conventional spray dryer, but at one-quarter to one-third the size.
- GSA generated lower particulate loading than a conventional spray dryer, enabling compliance with a lower ESP efficiency.
- Special steels were not required in construction, and only a single spray nozzle is needed.
- High availability and reliability similar to other commercial applications were demonstrated, reflecting simple design.

Economic

- Capital and levelized (15-year) costs for GSA installed in a 300-MWe plant using 2.6% sulfur coal are compared below to costs for a wet limestone scrubber with forced oxidation (WLFO scrubber). EPRI's TAG™ cost method was used. Based on EPRI cost studies of FGD processes, the capital cost (1990$) for a conventional spray dryer was $172/kW.

	Capital Cost (1990 $/kW)	**Levelized Cost (mills/kWh)**
GSA—3 units at 50% capacity	149	10.35
WLFO	216	13.04

Project Summary

The GSA has a capability of suspending a high concentration of solids, effectively drying the solids, and recirculating the solids at a high rate with precise control. This results in SO_2 control comparable to that of wet scrubbers and high lime utilization. The high concentration of solids provides the sorbent/SO_2 contact area. The drying enables low approach-to-saturation temperature and chloride usage. The rapid, precise, integral recycle system sustains the high solids concentration. The high lime utilization mitigates the largest operating cost (lime) and further reduces costs by reducing the amount of by-product generated. The GSA is distinguished from the average spray dryer by its modest size, simple means of introducing reagent to the reactor, direct means of recirculating unused lime, and low reagent consumption. Also, injected slurry coats recycled solids, not the walls, avoiding corrosion and enabling use of carbon steel in fabrication.

Environmental Performance

Exhibit 5-11 lists the six variables used in the factorial tests and the levels at which they were applied. Inlet flue gas temperature was held constant at 320 ºF. Factorial testing showed that lime stoichiometry had the greatest effect on SO_2 removal. Approach-to-saturation temperature was the next most important factor, followed closely by chloride levels. Although an approach-to-saturation temperature of 8 ºF was achieved without plugging the system, the test was conducted at a very low chloride level (0.04%). Because water evaporation rates decrease as chloride levels increase, an 18 ºF approach-to-saturation temperature was chosen for the higher 0.12% coal chloride level. Exhibit 5-12 summarizes key results from factorial testing.

A 28-day continuous run to evaluate the GSA/ESP configuration was made with bituminous coals averaging 2.7% sulfur, 0.12% chloride levels, and 18 ºF approach-to-saturation temperature. A subsequent 14-day continuous run to evaluate the GSA/PJBH configuration was performed under the same conditions as those of the 28-day run, except for adjustments in flyash injection rate from 1.5–1.0 gr/ft^3 (actual).

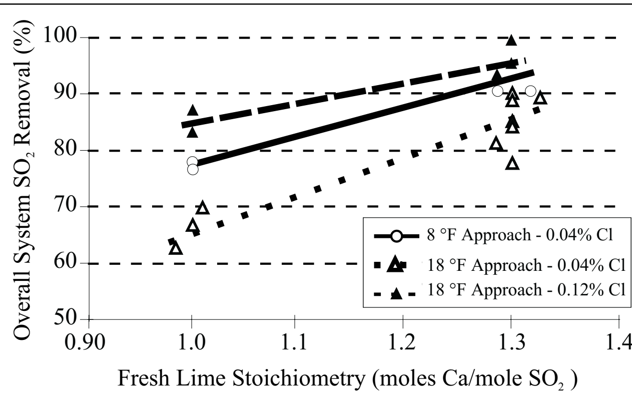
The 28-day run on the GSA/ESP system showed that the overall SO_2 removal efficiency averaged slightly more than 90%, very close to the set point of 91%, at an average Ca/S molar ratio of 1.40–1.45 moles $Ca(OH)_2$/mole inlet SO_2. The system was able to adjust rapidly to the surge in inlet SO_2 caused by switching to 3.5% sulfur Warrior Basin coal for a week. Lime utilization averaged 66.1%. The particulate removal efficiency averaged 99.9+% and emission rates were maintained below 0.015 lb/10^6 Btu. The 14-day run on the GSA/PJBH system showed that the SO_2 removal efficiency averaged more than 96% at an average Ca/S molar ratio of 1.34–1.43 moles $Ca(OH)_2$/mole inlet SO_2. Lime utilization averaged 70.5%. The particulate removal efficiency averaged 99.99+% and emission rates ranged from 0.001–0.003 lb/10^6 Btu.

Exhibit 5-11
Variables and Levels Used in GSA Factorial Testing

Variable	Level
Approach-to-saturation temperature (°F)	8*, 18, 28
Ca/S (moles $Ca(OH)_2$/mole inlet SO_2)	1.00 and 1.30
Flyash loading (gr/ft^3, actual)	0.50 and 2.0
Coal chloride level (%)	0.04 and 0.12
Flue gas flow rate (10^3 scfm)	14 and 20
Recycle screw speed (rpm)	30 and 45

*8 °F was only run at the low coal chloride level.

Exhibit 5-12
GSA Factorial Testing Results



Note: All tests were conducted at a 320 °F inlet flue gas temperature.

All air toxics tests were conducted with 2.7% sulfur, low-chloride coal with a 12 ºF approach-to-saturation temperature and a high flyash loading of 2.0 gr/ft^3 (actual). The GSA/ESP arrangement indicated average removal efficiencies of greater than 99% for arsenic, barium, chromium, lead, and vanadium; somewhat less for manganese; and less than 99% for antimony, cadmium, mercury, and selenium. The GSA/PJBH configuration showed 99+% removal efficiencies for arsenic, barium, chromium, lead, manganese, selenium, and vanadium; with cadmium removal much lower and mercury removal lower than that of the GSA/ESP system. The removal of HCl and HF was dependent upon the utilization of lime slurry and was relatively independent of particulate control configuration. Removal efficiencies were greater than 98% for HCl and 96% for HF.

Operational Performance

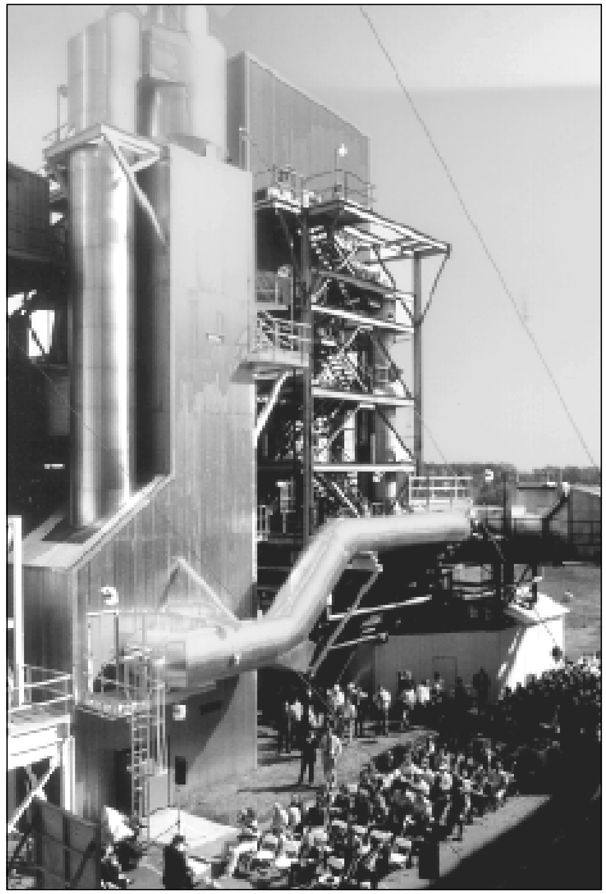
Because the GSA system has suspended recycle solids to provide a contact area for SO_2 capture, multiple high-pressure atomizer nozzles or high-speed rotary nozzles to achieve uniform, fine droplet size are not required. Also, recycle of solids is direct and avoids recycling material in the feed slurry, which would necessitate expensive abrasion-resistant materials in the atomizer(s).

The high heat and mass transfer characteristics of the GSA enable the GSA system to be significantly smaller than a conventional spray dryer for the same capacity—one-quarter to one-third the size. This makes retrofit feasible for space-confined plants and reduces installation cost. The GSA system slurry is sprayed on the recycled solids, not the reactor walls, avoiding direct wall contact and the need for corrosion-resistant alloy steels. Furthermore, the high concentration of rapidly moving solids scours the reactor walls and mitigates scaling. The GSA system generates a significantly lower grain loading than a conventional spray dryer—2–5 gr/ft^3 for GSA versus 6–10 gr/ft^3 for a spray dryer—enabling compliance even with lower ESP particulate removal efficiency. The GSA system produces a solid by-product containing very low moisture. This material contains both fly ash and unreacted lime. With the addition of water, the by-product undergoes a pozzolanic reaction, essentially providing the characteristics of a low-grade cement.

Economic Performance

Using EPRI costing methods, which have been applied to 30 to 35 other FGD processes, economics were estimated for a moderately difficult retrofit of a 300-MWe boiler burning 2.6% sulfur coal. The design SO_2 removal efficiency was 90% at a lime feed rate equivalent to 1.30 moles of Ca/mole inlet SO_2. Lime was assumed to be 2.8 times the cost of limestone. It was determined that (1) capital cost was \$149/kW (1990\$) with three units at 50% capacity, and (2) levelized cost (15-year) was 10.35 mills/kWh with three units at 50% capacity.

A cost comparison run for a WLFO scrubber showed the capital and levelized costs to be \$216/kW and 13.04 mills/kWh, respectively. The capital cost listed in EPRI cost tables for a conventional spray dryer at 300-MWe and 2.6% sulfur coal was \$172/kW (1990\$). Also, because the GSA requires less power and has better lime utilization than a spray dryer, the GSA will have a lower operating cost.



▲ AirPol, Inc. successfully demonstrated the GSA system at TVA's Center for Emissions Research.

Commercial Applications

The low capital cost, moderate operating cost, and high SO_2 capture efficiency make the GSA system particularly attractive as a CAAA compliance option for boilers in the 50- to 250-MWe range. Other major advantages include the modest space requirements comparable to duct injection systems; high availability/reliability owing to design simplicity; and low dust loading, minimizing particulate upgrade costs.

GSA market entry was significantly enhanced with the sale of a 50-MWe unit, worth \$10 million, to the city of Hamilton, Ohio, subsidized by the Ohio Coal Development Office. A sale worth \$1.3 million has been made to the U.S. Army for hazardous waste disposal. A GSA system has been sold to a Swedish iron ore sinter plant. Sales to Taiwan and India have a combined value of \$5.5 million.

Contacts

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- *10-MW Demonstration of Gas Suspension Absorption Final Public Design Report*. Report No. DOE/PC/90542-T10. AirPol, Inc. June 1995. (Available from NTIS as DE960003270.)
- *SO_2 Removal Using Gas Suspension Absorption Technology*. Topical Report No. 4. U.S. Department of Energy and AirPol, Inc. April 1995.
- *10-MWe Demonstration of the Gas Suspension Absorption Process at TVA's Center for Emissions Research: Final Report.* Report No. DOE/PC/90542-T10. Tennessee Valley Authority. March 1995. (Available from NTIS as DE96000327.)

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Participant

Bechtel Corporation

Additional Team Members

Pennsylvania Electric Company—cofunder and host
Pennsylvania Energy Development Authority—cofunder
New York State Electric % Gas Corporation—cofunder
Rockwell Lime Company—cofunder

Location

Seward, Indiana County, PA (Pennsylvania Electric Company's Seward Station, Unit No. 5)

Technology

Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process

Plant Capacity/Production

73.5-MWe equivalent

Coal

Pennsylvania bituminous, 1.2–2.5% sulfur

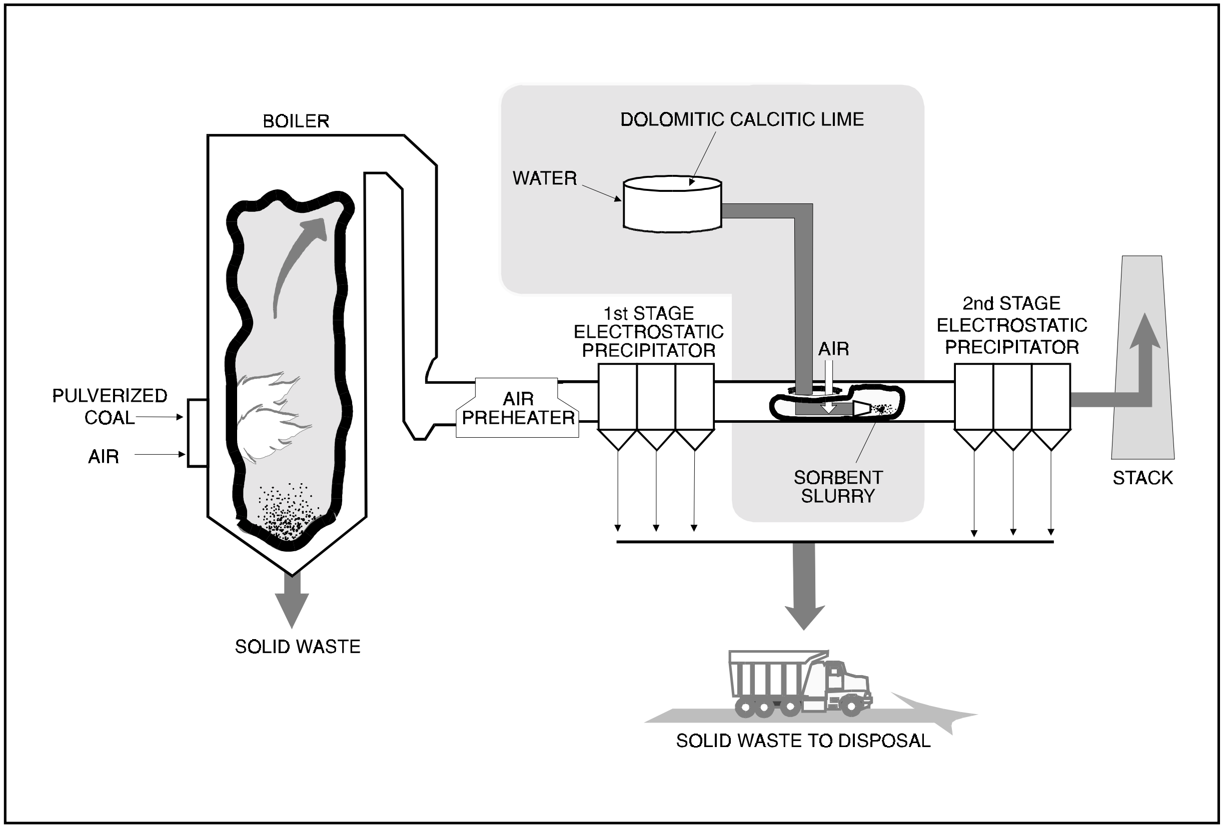
Project Funding

Total project cost*	$10,411,600	100%
DOE	5,205,800	50
Participant	5,205,800	50

Project Objective

To demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.

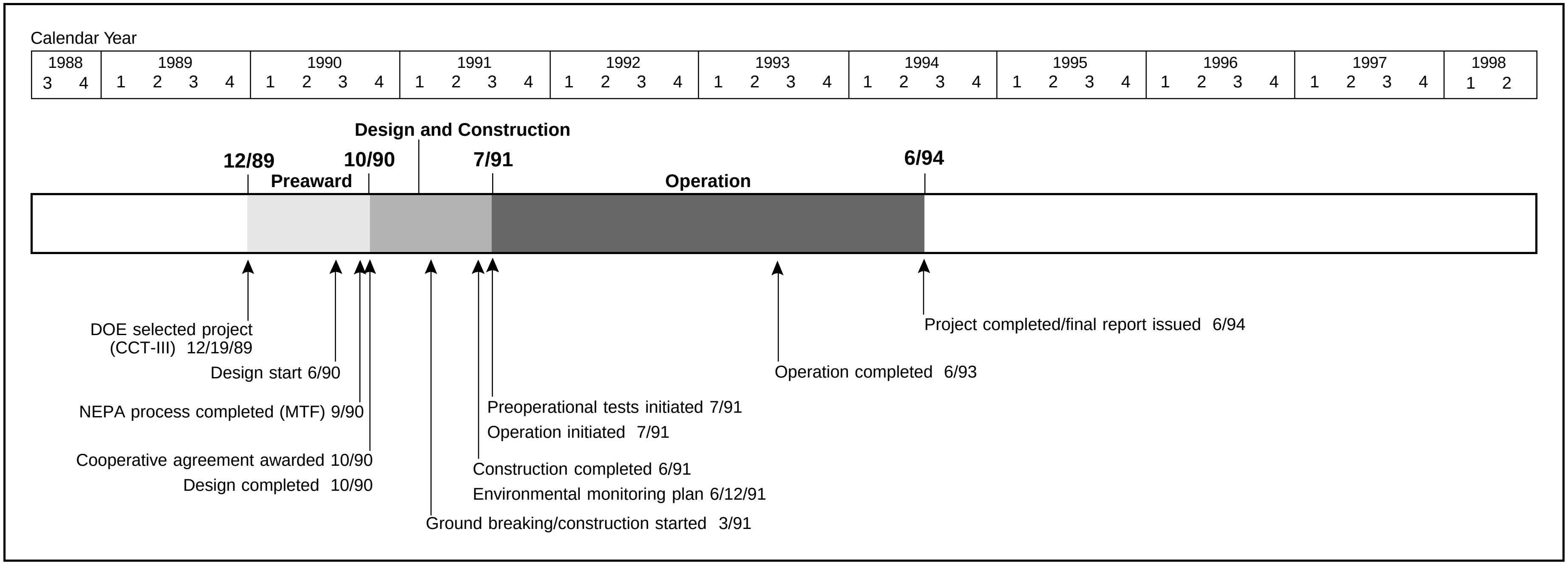
*Additional project overrun costs were funded 100% by the participant for a final total project cost of $12,173,000.



Technology/Project Description

In Bechtel's CZD/FGD process, a finely atomized slurry of reactive lime is sprayed into the flue gas stream between the boiler air heater and the electrostatic precipitator (ESP). The lime slurry is injected into the center of the duct by spray nozzles designed to produce a cone of fine spray. As the spray moves downstream and expands, the gas within the cone cools and the SO_2 is quickly absorbed in the liquid droplets. The droplets mix with the hot flue gas, and the water evaporates rapidly. Fast drying precludes wet particle buildup in the duct and aids the flue gas in carrying the dry reaction products and the unreacted lime to the ESP.

This project included injection of different types of sorbents (dolomitic and calcitic limes) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO_2 removal and the capability of the ESP to control particulates. The demonstration was conducted at Pennsylvania Electric Company's Seward Station in Seward, PA. One-half of the flue gas capacity of the 147-MWe Unit No. 5 was routed through a modified, longer duct between the first- and second-stage ESPs.



Results Summary

Environmental

- Pressure-hydrated dolomitic lime proved to be a more effective sorbent than either dry hydrated calcitic lime or freshly slaked calcitic lime.
- Sorbent injection rate was the most influential parameter on SO_2 capture. Flue gas temperature was the limiting factor on injection rate. For SO_2 capture efficiency of 50% or more, a flue gas temperature of 300 ºF or more was needed.
- Slurry concentration for a given sorbent did not increase SO_2 removal efficiency beyond a certain threshold concentration.
- Testing indicated that SO_2 removal efficiencies of 50% or more were achievable with flue gas temperatures of 300–310 ºF (full load), sorbent injection rate of 52–57 gal/min, residence time of 2 seconds, and a pressure-hydrated dolomitic-lime concentration of about 9%.
- For operating conditions at Seward Station, data indicated that for 40–50% SO_2 removal, a 6–8% lime or dolomitic lime slurry concentration, and a stoichiometric ratio of 2–2.5 resulted in a 40–50% lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO were required for every mole of SO_2 removed.
- Assuming 92% lime purity, 1.9–2.4 tons of lime was required for every ton of SO_2 removed.

Operational

- About 100 ft of straight duct was required to assure the 2-second residence time needed for effective CZD/FGD operation.
- At Seward Station, stack opacity was not detrimentally affected by CZD/FGD.
- Availability of CZD/FGD was very good.
- Some CZD/FGD modification will be necessary to assure consistent SO_2 removal and avoid deposition of solids within the ductwork during upsets.

Economic

- Capital cost of a 500-MWe system operating on 4% sulfur coal and achieving 50% SO_2 reduction was estimated at less than \$30/kW and operating cost at \$300/ton of SO_2 removed (1994\$).

Project Summary

The principle of the CZD/FGD is to form a wet zone of slurry droplets in the middle of a duct confined in an envelope of hot gas between the wet zone and the hot gas. The lime slurry reacts with part of the SO_2 in the gas and the reaction products dry to form solid particles. An ESP, downstream from the point of injection, captures the reaction products along with the fly ash entrained in the flue gas.

CZD/FGD did not require a special reactor, simply a modification to the ductwork. Use of the commercially available Type S pressure-hydrated dolomitic lime reduced residence time requirements for CZD/FGD and enhanced sorbent utilization. The increased humidity of CZD/FGD processed flue gas enhanced ESP performance, eliminating the need for upgrades to handle the increased particulate load.

▲ Bechtel's demonstration showed that 50% SO_2 removal efficiency was possible using CZD/FGD technology. The extended duct into which lime slurry was injected is in the foreground.

Bechtel began its 18-month, two-part test program for the CZD process in July 1991, with the first 12 months of the test program consisting primarily of parametric testing and the last 6 months consisting of continuous operational testing. During the continuous operational test period, the system was operated under fully automatic control by the host utility boiler operators. The new atomizing nozzles were thoroughly tested both outside and inside the duct prior to testing.

The SO_2 removal parametric test program, which began in October 1991, was completed in August 1992. Specific objectives were as follows:

- Achieve projected SO_2 removal of 50%
- Realize SO_2 removal costs of less than $300/ton
- Eliminate negative effects on normal boiler operations without increasing particulate emissions and opacity

The parametric tests included duct injection of atomized lime slurry made of dry hydrated calcitic lime, freshly slaked calcitic lime, and pressure-hydrated dolomitic lime. All three reagents remove SO_2 from the flue gas but require different feed concentrations of lime slurry for the same percentage of SO_2 removed. The most efficient removals and easiest to operate system were obtained using pressure-hydrated dolomitic lime.

Environmental Performance

Sorbent injection rate proved to be the most influential factor on SO_2 capture. The rate of injection possible was limited by the flue gas temperature. This impacted a portion of the demonstration when air leakage caused flue gas temperature to drop from 300–310 ºF to 260–280 ºF. At 300–310 ºF, injection rates of 52–57 gal/min were possible and SO_2 reductions greater than 50% were achieved. At 260–280 ºF, injection rates had to be dropped to 30–40 gal/min, resulting in a 15–30% drop in SO_2 removal efficiency. Slurry concentration for a given sorbent did not increase SO_2 removal efficiency beyond a certain threshold concentration. For example, with pressure-hydrated dolomitic lime, slurry concentrations above 9% did not increase SO_2 capture efficiency.

Parametric tests indicated that SO_2 removals above 50% are possible under the following conditions: flue gas temperature of 300–310 ºF; boiler load of 145- to 147-MWe; residence time in the duct of 2 seconds; and lime slurry injection rate of 52–57 gal/min.

Operational Performance

The percentage of lime utilization in the CZD/FGD significantly affected the total cost of SO_2 removal. An analysis of the continuous operational data indicated that the percentage of lime utilization was directly dependent on two key factors: (1) percentage of SO_2 removed, and (2) lime slurry feed concentration.

For operating conditions at Seward Station, data indicated that for 40–50% SO_2 removal, a 6–8% lime or dolomitic lime slurry concentration, and a stoichiometric ratio of 2–2.5 resulted in a 40–50% lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO were required for every mole of SO_2 removed; or assuming 92% lime purity, 1.9–2.4 tons of lime were required for every ton of SO_2 removed. In summary, the demonstration showed the following results:

- A 50% SO_2 removal efficiency with CZD/FGD was possible.
- Drying and SO_2 absorption required a residence time of 2 seconds, which required a long and straight horizontal gas duct of about 100 feet.
- The fully automated system integrated with the power plant operation demonstrated that the CZD/FGD process responded well to automated control operation. However, modifications to the CZD/FGD were required to assure consistent SO_2 removal and avoid deposition of solids within the gas duct during upsets.

- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.

Economic Performance

The CZD/FGD process can achieve costs of $300/ton of SO_2 removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for 50% SO_2 removal, the total capital cost is estimated to be less than $30/kW (1994$).

Commercial Applications

After the conclusion of the DOE-funded CZD/FGD demonstration project at Seward Station, the CZD/FGD system was modified to improve SO_2 removal during continuous operation while following daily load cycles. Bechtel and the host utility, Pennsylvania Electric Company, continued the CZD/FGD demonstration for an additional year. Results showed that CZD/FGD operation at SO_2 removal rates lower than 50% could be sustained over long periods without significant process problems.

CZD/FGD can be used for retrofit of existing plants and installation in new utility boiler flue gas facilities to remove SO_2 from a wide variety of sulfur-containing coals. A CZD/FGD system can be added to a utility boiler with a capital investment of about $25–50/kW of installed capacity, or approximately one-fourth the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, low energy requirements, fully automated operation, and production of only nontoxic, disposable waste. The CZD/FGD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. The CZD/FGD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

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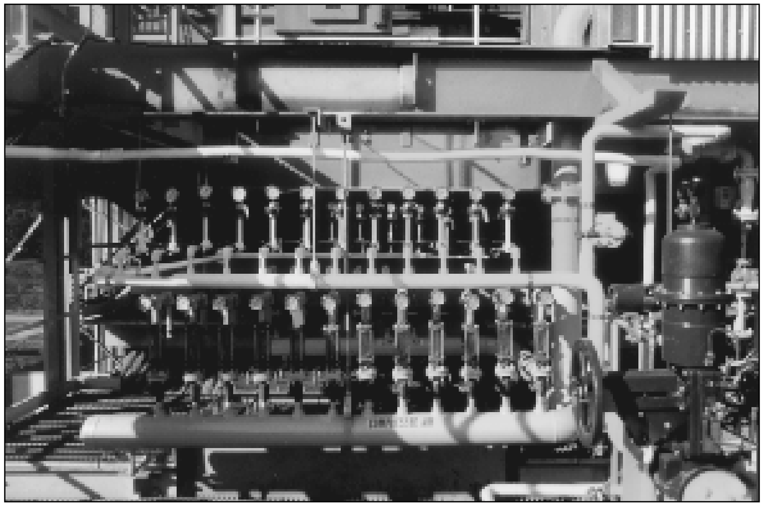


▲ This photo shows the CZD/FGD lime slurry injector control system.

LIFAC Sorbent Injection Desulfurization Demonstration Project

Project completed.

Participant

LIFAC-North America (a joint venture partnership between Tampella Power Corporation and ICF Kaiser Engineers, Inc.)

Additional Team Members

ICF Kaiser Engineers, Inc.—cofunder and project manager
Tampella Power Corporation—cofunder
Tampella, Ltd.—technology owner
Richmond Power and Light—cofunder and host utility
Electric Power Research Institute—cofunder
Black Beauty Coal Company—cofunder
State of Indiana—cofunder

Location

Richmond, Wayne County, IN (Richmond Power % Light's Whitewater Valley Station, Unit No. 2)

Technology

LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor

Plant Capacity/Production

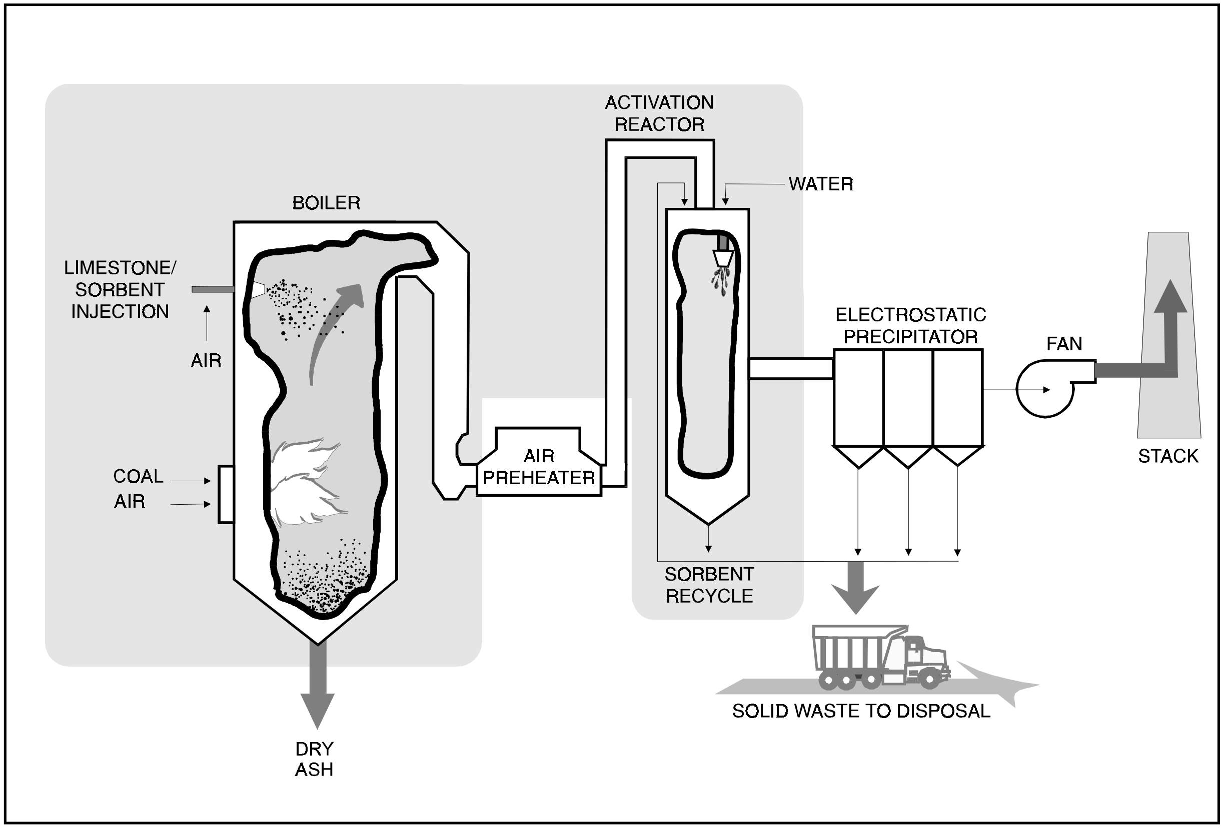
60-MWe

Coal

Bituminous, 2.0–2.8% sulfur

Project Funding

Total project cost	$21,393,772	100%
DOE	10,636,864	50
Participants	10,756,908	50



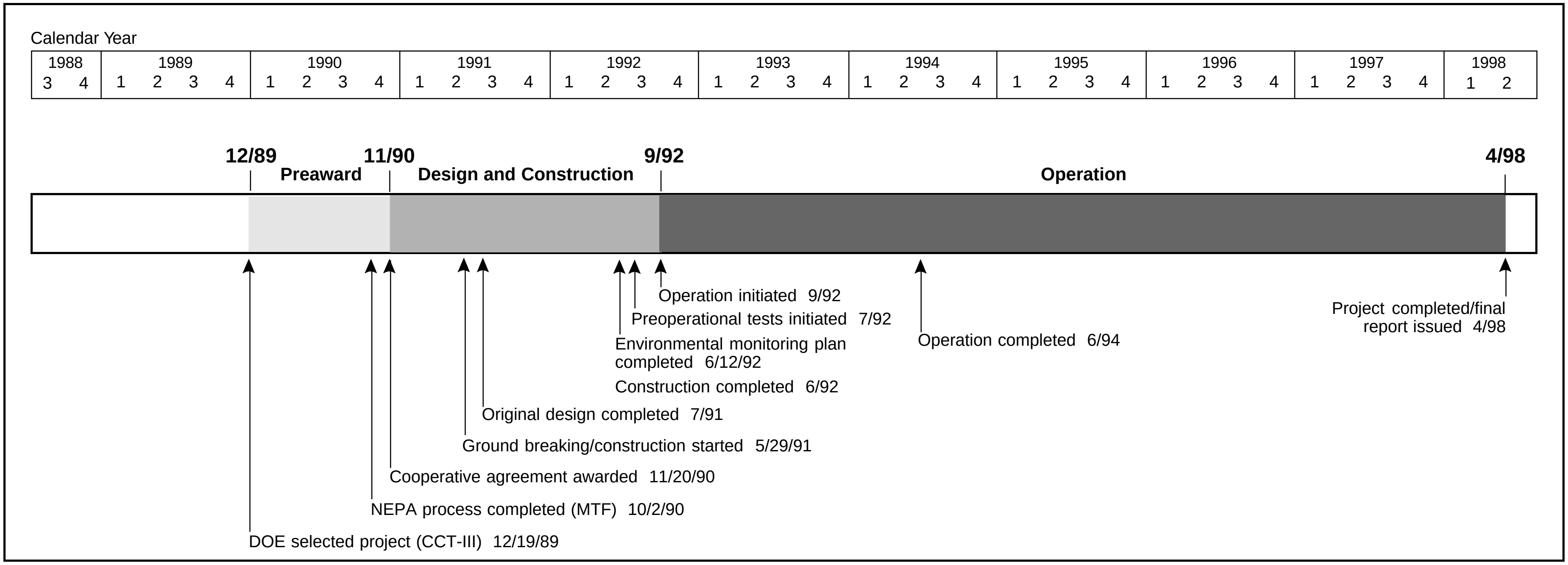
Project Objective

To demonstrate that electric power plants—especially those with space limitations and burning high-sulfur coals—can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO_2 from flue gas and produce a dry solid waste product for disposal in a landfill.

Technology/Project Description

Pulverized limestone is pneumatically blown into the upper part of the boiler near the superheater where it absorbs some of the SO_2 in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO_2 downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO_2 capture. After leaving the chamber, the sorbent is easily separated from the flue gas along with the fly ash in the electrostatic precipitator (ESP). The sorbent material from the reactor and electrostatic precipitator are recirculated back through the reactor for increased efficiency. The waste is dry, making it easier to handle than the wet scrubber sludge produced by conventional wet limestone scrubber systems.

The technology enables power plants with space limitations to use high-sulfur midwestern coals by providing an injection process that removes 75–85% of the SO_2 from flue gas and produces a dry solid waste product suitable for disposal in a landfill.



Results Summary

Environmental

- SO_2 removal efficiency was 70% at a calcium-to-sulfur (Ca/S) molar ratio of 2.0, approach-to-saturation temperature of 7–12 ºF, and limestone fineness of 80% minus 325 mesh.
- SO_2 removal efficiency with limestone fineness of 80% minus 200 mesh was 15% lower at a Ca/S molar ratio of 2.0 and 7–12 ºF approach-to-saturation temperature.
- The four parameters having the greatest influence on sulfur removal efficiency were limestone fineness, Ca/S molar ratio, approach-to-saturation temperature, and ESP ash recycle rate.
- ESP ash recycle rate was limited in the demonstration system configuration. Increasing the recycle rate and sustaining a 5 ºF approach-to-saturation temperature were projected to increase SO_2 removal efficiency to 85% at a Ca/S molar ratio of 2.0 (fine limestone).
- ESP efficiency and operating levels were essentially unaffected by LIFAC operation during steady-state operation.
- Fly and bottom ash were dry and readily disposed of at a local landfill. The quantity of additional solid waste can be determined by assuming that approximately 4.3 tons of limestone is required to remove 1.0 ton of SO_2.

Operational

- When operating with fine limestone (80% minus 325 mesh), the soot-blowing cycle had to be reduced from 6.0 to 4.5 hours.
- Automated programmable logic and simple design make the LIFAC system easy to operate in startup, shutdown, or normal duty cycles.
- The amount of bottom ash increased slightly, but there was no negative impact on the ash-handling system.

Economic

- Capital cost—$66/kW for two LIFAC reactors (300-MWe); $76/kW for one LIFAC reactor (150-MWe); $99/kW for one LIFAC reactor (65-MWe) (1994$).
- Operating cost—$65/ton of SO_2 removal, assuming 75% SO_2 capture, Ca/S molar ratio of 2.0, limestone composed of 95% $CaCO_3$, and costing $15/ton.

Project Summary

The LIFAC technology was designed to enhance the effectiveness of dry sorbent injection systems for SO_2 control and to maintain the desirable aspects of low capital cost and compactness for ease of retrofit. Furthermore, limestone was used as the sorbent (about 1/3 of the cost of lime) and a sorbent recycle system was incorporated to reduce operating costs.

The process evaluation test plan was composed of five distinct phases each having its own objectives. These tests were as follows:

- Baseline tests characterized the operation of the host boiler and associated subsystems prior to LIFAC operations.
- Parametric tests were designed to evaluate the many possible combinations of LIFAC process parameters and their effect on SO_2 removal.
- Optimization tests were performed after the parametric tests to evaluate the reliability and operability of the LIFAC process over short, continuous operating periods.
- Long-term tests were performed to demonstrate LIFAC's performance under commercial operating conditions.
- Post-LIFAC tests involved repeating the baseline test to identify any changes caused by the LIFAC system.

The coals used during the demonstration varied in sulfur content from 1.4–2.8%. However, most of the testing was conducted with the higher sulfur coals (2.0–2.8% sulfur).

Environmental Performance

During the parametric testing phase, the numerous LIFAC process values and their effects on sulfur removal efficiency were evaluated. The four major parameters having the greatest influence on sulfur removal efficiency were limestone fineness Ca/S molar ratio, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO_2 capture was about 15% better when injecting fine limestone (80% minus 325 mesh) than it was with coarse limestone (80% minus 200 mesh).

While injecting the fine limestone, the soot blowing frequency had to be increased from 6-hour to 4.5-hour cycles. The coarse-quality limestone did not affect soot blowing but was found to be more abrasive on the feed and transport hoses.

Parametric tests indicated that a 70% SO_2 reduction was achievable with a Ca/S molar ratio of 2.0. ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO_2 capture. The large quantity of ash removed from the LIFAC reactor bottom and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70% less than had been anticipated. However, this low recycling rate was found to affect SO_2 capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5% increase in SO_2 removal efficiency. It was estimated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 ºF above saturation temperature, an SO_2 reduction of 85% could be maintained.

Operational Performance

Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60-MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to boiler load changes. A Ca/S molar ratio of 2.0 was selected to attain SO_2 reductions above 70%. Reactor bottom temperature was about 5 ºF higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during the long-term tests included the degree of humidification, grind size of the high-calcium-content limestone, and recycle of spent sorbent from the ESP.

Long-term testing showed that SO_2 reductions of 70% or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10%) and ESP efficiency was high (99.2%). The amount of boiler bottom ash increased slightly during testing, but there was no negative impact on the power plant's bottom and flyash removal system. The solid waste generated was a mixture of fly ash and calcium compounds and was readily disposed of at a local landfill.

▲ The LIFAC system successfully demonstrated at Whitewater Valley Station Unit No. 2 is being retained by Richmond Power % Light for commercial use with high-sulfur coal. There are 10 full-scale LIFAC units in Canada, China, Finland, Russia, and the United States.

The LIFAC system proved to be highly operable because it has few moving parts and is simple to operate.

▲ The top of the LIFAC reactor is shown being lifted into place. During 2,800 hours of operation, long-term testing showed that SO_2 reductions of 70% or more could be sustained under normal boiler operation.

The process can be easily shut down and restarted. The process is automated by a programmable logic system that regulates process control loops, interlocking, startup, shutdowns, and data collection. The entire LIFAC process was easily managed via two personal computers located in the host utility's control room.

Economic Performance

The economic evaluation indicated that the capital cost of a LIFAC installation is lower than for either a spray dryer or wet scrubber. Capital costs for LIFAC technology vary, depending on unit size and the quantity of reactors needed:

- $99/kW for one LIFAC reactor at Whitewater Valley Station (65-MWe) (1994$),
- $76/kW for one LIFAC reactor at Shand Station (150-MWe), and
- $66/kW for two LIFAC reactors at Shand Station (300-MWe).

Crushed limestone accounts for about one-half of LIFAC's operating costs. LIFAC requires 4.3 tons of limestone to remove 1.0 ton of SO_2, assuming 75% SO_2 capture, a Ca/S molar ratio of 2.0, and limestone containing 95% $CaCO_3$. Assuming limestone costs of $15/ton, LIFAC's operating cost would be $65/ton of SO_2 removed.

Commercial Applications

There are 10 full-scale LIFAC units in operation in Canada, China, Finland, Russia, and the United States. The LIFAC system at Richmond Power % Light is the first to be applied to a power plant using high-sulfur (2.0–2.9%) coal. The LIFAC system is being retained by Richmond Power % Light at Whitewater Valley Station, Unit No. 2. The other LIFAC installations on power plants are using bituminous and lignite coals having lower sulfur contents (0.6–1.5%).

Contacts

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- *LIFAC Sorbent Injection Desulfurization Demonstration Project. Final Report, Vol. II: Project Performance and Economics.* LIFAC-North America. February 1998. (Available from NTIS as DE96004421.)
- "LIFAC Nearing Marketability." *Clean Coal Today.* Report No. DOE/FE-0215P-21. Spring 1996.
- Viiala, J., *et al.* "Commercialization of the LIFAC Sorbent Injection Process in North America." *Third Annual Clean Coal Technology Conference: Technical Papers.* September 1994.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: LIFAC Sorbent Injection Desulfurization Demonstration Project.* LIFAC-North America. Report No. DOE/FE-0207P. U.S. Department of Energy, October 1990. (Available from NTIS as DE91001077.)

Advanced Flue Gas Desulfurization Demonstration Project

Project completed.

Participant

Pure Air on the Lake, L.P. (a subsidiary of Pure Air, which is a general partnership between Air Products and Chemicals, Inc. and Mitsubishi Heavy Industries America, Inc.)

Additional Team Members

Northern Indiana Public Service Company—cofunder and host

Mitsubishi Heavy Industries, Ltd.—process designer

Stearns-Roger Division of United Engineers and Constructors—facility designer

Air Products and Chemicals, Inc.—constructor and operator

Location

Chesterton, Porter County, IN (Northern Indiana Public Service Company's Bailly Generating Station, Unit Nos. 7 and 8)

Technology

Pure Air's advanced flue gas desulfurization (AFGD) process

Plant Capacity/Production

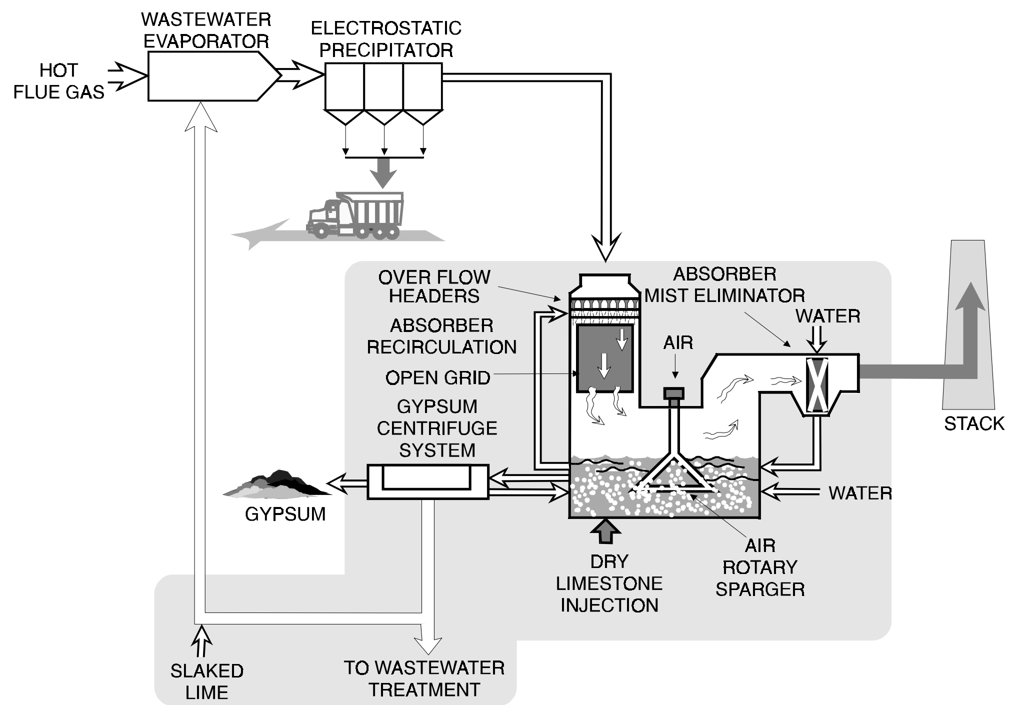
528-MWe

Coal

Bituminous, 2.0–4.5% sulfur

Project Funding

Total project cost	$151,707,898	100%
DOE	63,913,200	42
Participant	87,794,698	58



Project Objective

To reduce SO_2 emissions by 95% or more at approximately one-half the cost of conventional scrubbing technology, significantly reduce space requirements, and create no new waste streams.

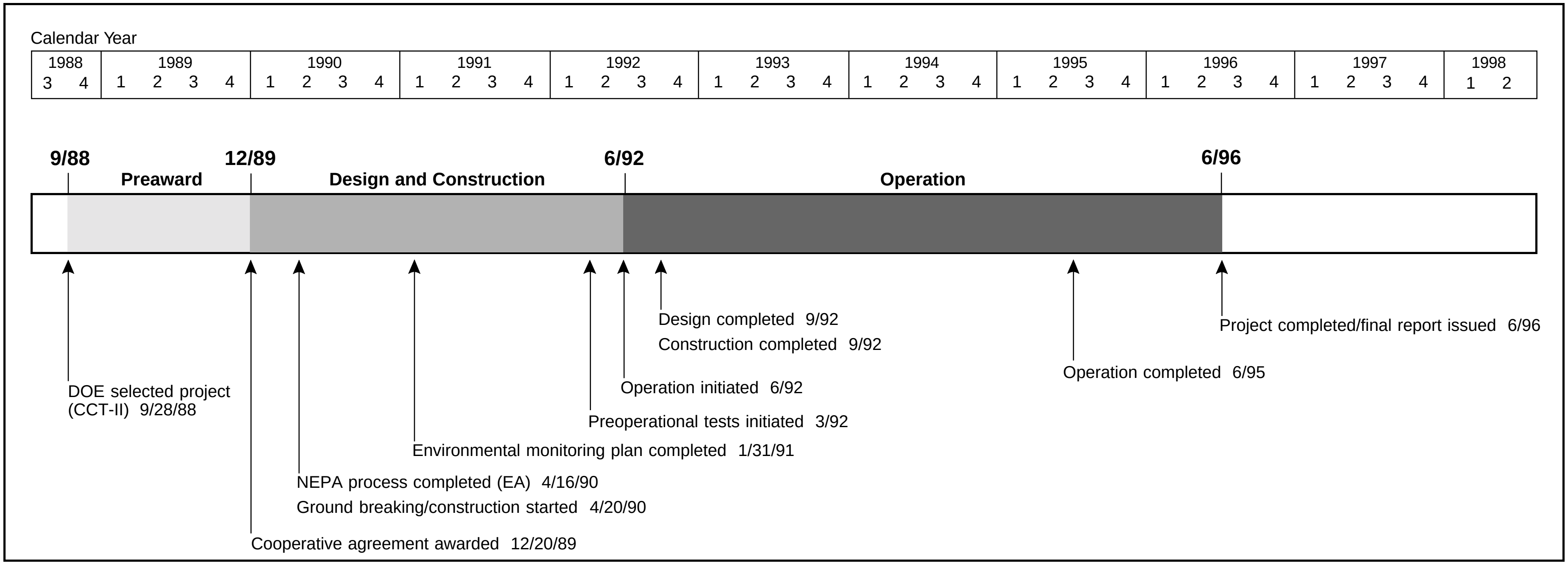
Technology/Project Description

Pure Air built a single SO_2 absorber for a 528-MWe power plant. Although the largest capacity absorber module of its time in the United States, space requirements were modest because no spare or backup absorber modules were required. The absorber performed three functions in a single vessel: prequenching, absorbing, and oxidation of sludge to gypsum. Additionally, the absorber was of a co-current design, in which the flue gas and scrubbing slurry move in the same direction and at a relatively high velocity compared to that in conventional scrubbers. These features all combined to yield a state-of-the-art SO_2 absorber that was more compact and less expensive than contemporary conventional scrubbers.

Other technical features included the injection of pulverized limestone directly into the absorber, a device called an air rotary sparger located within the base of the absorber, and a novel wastewater evaporation system. The air rotary sparger combined the functions of agitation and air distribution into one piece of equipment to facilitate the oxidation of calcium sulfite to gypsum.

Pure Air also demonstrated a unique gypsum agglomeration process, PowerChip®, to significantly enhance handling characteristics of adsorbed flue gas desulfurization (AFGD)-derived gypsum.

PowerChip is a registered trademark of Pure Air on the Lake, L.P.



Results Summary

Environmental

- AFGD design enabled a single 600-MWe absorber module without spares to remove 95% or more SO_2 at availabilities of 99.5% when operating with high-sulfur coals.
- Wallboard-grade gypsum was produced in lieu of solid waste, and all gypsum produced was sold commercially.
- The wastewater evaporation system (WES) mitigated expected increases in wastewater generation associated with gypsum production and showed the potential for achieving zero wastewater discharge (only a partial-capacity WES was installed).
- PowerChip® increased the market potential for AFGD-derived gypsum by cost effectively converting it to a product with the handling characteristics of natural rock gypsum.
- Air toxics testing established that all acid gases were effectively captured and neutralized by the AFGD. Trace elements largely became constituents of the solids streams (bottom ash, fly ash, gypsum product). Some boron, selenium, and mercury passed to the stack gas in a vapor state.

Operational

- AFGD use of co-current, high-velocity flow; integration of functions; and a unique air rotary sparger proved to be highly efficient, reliable (to the exclusion of requiring a spare module), and compact. The compactness, combined with no need for a spare module, significantly reduced space requirements.
- The own-and-operate contractual arrangement whereby Pure Air took on the turnkey, financing, operating, and maintenance risks through performance guarantees was successful.

Economic

- Capital costs and space requirements for AFGD were about half those of conventional systems.

Project Summary

The project proved that single absorber modules of advanced design could process large volumes of flue gas and provide the required availability and reliability without the usual spares. The major performance objectives were met.

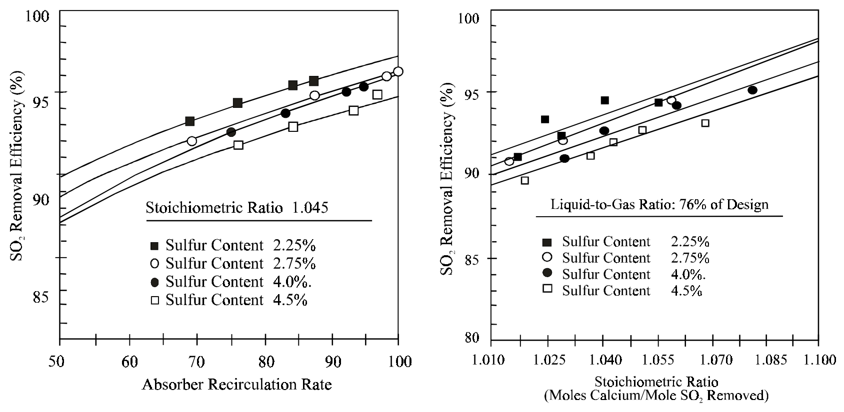
Over the 3-year demonstration, the AFGD unit accumulated 26,280 hours of operation with an availability of 99.5%. Approximately 237,000 tons of SO_2 were removed, with capture efficiencies of 95% or more, and over 210,000 tons of salable gypsum were produced. The AFGD continues in commercial service, which includes sale of all by-product gypsum to U.S. Gypsum's East Chicago, Indiana wallboard production plant.

Environmental Performance

Testing over the 3-year period clearly established that AFGD operating within its design parameters (without additives) could consistently achieve 95% SO_2 reduction or more with 2.0–4.5% sulfur coals. The design range for the calcium-to-sulfur stoichiometric ratio was 1.01–1.07, with the upper value set by gypsum purity requirements (*i.e.*, amount of unreacted reagent allowed in the gypsum). Another key control parameter was the ratio L/G, which is the amount of reagent slurry injected into the absorber grid (L) to the volume of flue gas (G). The design L/G range was 50–128 gal/1,000 ft^3. The lower end was determined by solids settling rates in the slurry and the requirement for full wetting of the grid packing. The high end was determined by where performance leveled out.

Five coals with differing sulfur contents were selected for parametric testing to examine SO_2 removal efficiency as a function of load, sulfur content, stoichiometric ratio, and L/G. Loads tested were 33%, 67%, and 100%. High removal efficiencies, well above 95%, were possible at loads of 33% and 67% with low to moderate stoichiometric ratio and L/G settings, even for 4.5% sulfur coal. Exhibit 5-13 summarizes the results of parametric testing at full load.

Exhibit 5-13
SO_2 Removal Performance
(100% Boiler Load)



In the AFGD process, chlorides that would have been released to the air are captured but potentially become a wastewater problem. This was mitigated by the addition of the WES, which takes a portion of the wastewater stream with high chloride and sulfate levels and injects it into the ductwork upstream of the ESP. The hot flue gas evaporated the water and the dissolved solids were captured in the ESP. Problems were experienced early on, with the WES nozzles failing to provide adequate atomization, and plugging as well. This was resolved by replacing the original single-fluid nozzles with dual-fluid systems employing air as the second fluid.

Commercial-grade gypsum quality (95.6–99.7%) was maintained throughout testing, even at the lower sulfur concentrations where the ratio of fly ash to gypsum increases due to lower sulfate availability. The primary importance of producing a commercial-grade gypsum is avoidance of the environmental and economic consequences of disposal. Marketability of the gypsum is dependent upon whether users are in range of economic transport and whether they can handle the gypsum by-product. For these reasons, PowerChip® technology was demonstrated as part of the project. This technology uses a compression mill to convert the highly cohesive AFGD gypsum cake into a flaked product with handling characteristics equivalent to natural rock gypsum. The process avoids use of binders, pre-drying or pre-calcining normally associated with briquetting, and is 30–55% cheaper at \$2.50–\$4.10/ton.

Air toxics testing established that all acid gases are effectively captured and neutralized by the AFGD. Trace elements largely become constituents of the solids streams (bottom ash, fly ash, gypsum product). Some boron, selenium, and mercury pass to the stack gas in a vapor state.

Operational Performance

Availability over the 3-year operating period averaged 99.5% while maintaining an average SO_2 removal efficiency of 94%. This was attributable to the simple, effective design and an effective operating/maintenance philosophy. Modifications were also made to the AFGD system. An example was the implementation of new alloy technology, C-276 alloy over carbon steel clad material, to replace alloy wallpaper construction within the absorber tower wet/dry interface. Also, use of co-current rather than conventional counter-current flow resulted in lower pressure drops across the absorber and afforded the flexibility to increase gas flow without an abrupt drop in removal efficiency. AFGD SO_2 capture efficiency with limestone was comparable to that in wet scrubbers using lime, which is far more expensive. The 24-hour power consumption was 5,275 kW, or 61% of expected consumption, and water consumption was 1,560 gal/min, or 52% of expected consumption.

Economic Performance

Exhibit 5-14 summarizes capital and levelized current dollar cost estimates for nine cases with varying plant capacity and coal sulfur content. A capacity factor of 65% and a sulfur removal efficiency of 90% were assumed. The calculation of levelized cost followed guidelines established in EPRI's Technical Assessment Guide™.

The incremental benefits of the own-and-operate arrangement, by-product utilization, and emission allowances were also evaluated. Exhibit 5-15 depicts the relative costs of a hypothetical 500-MWe generating unit in the Midwest burning 4.3% sulfur coal with a base case conventional FGD system and four incremental cases. The horizontal lines in Exhibit 5-15 show the range of costs for a fuel-switching option. The lower bar is the cost of fuel delivered to the hypothetical midwest unit and the upper bar allows for some plant modifications to accommodate the compliance fuel.

Commercial Applications

AFGD is positioned well to compete in the pollution control arena of 2000 and beyond. AFGD has markedly reduced cost and demonstrated the ability to compete with fuel switching under certain circumstances even with a first-generation system. Advances in technology, *e.g.*, in materials and components, should lower costs for AFGD. The own-and-operate business approach has done much to mitigate risk on the part of prospective users. High SO_2 capture efficiency places an AFGD user in the possible position to trade allowances or apply credits to other units within the utility. WES and PowerChip® mitigate or eliminate otherwise serious environmental concerns. AFGD effectively deals with hazardous air pollutants.

The project received *Power* magazine's 1993 Powerplant Award and the National Society of Professional Engineers' 1992 Outstanding Engineering Achievement Award.

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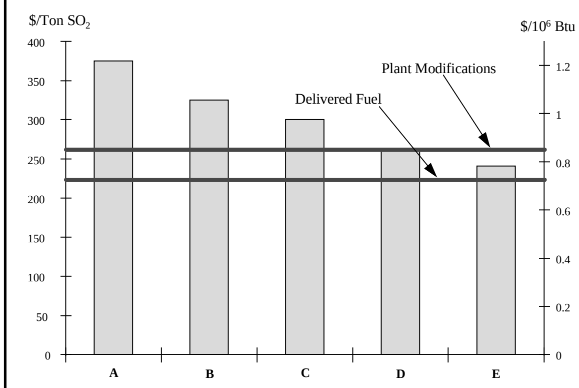
Exhibit 5-14
Estimated Costs for an AFGD System
(1995 Current Dollars)

Cases:	1	2	3	4	5	6	7	8	9
Plant size (MWe)	100	100	100	300	300	300	500	500	500
Coal sulfur content (%)	1.5	3.0	4.5	1.5	3.0	4.5	1.5	3.0	4.5
Capital cost ($/kW)	193	210	227	111	121	131	86	94	101
Levelized cost ($/ton SO_2)									
15-year life	1,518	840	603	720	401	294	536	302	223
20-year life	1,527	846	607	716	399	294	531	300	223
Levelized cost (mills/kWh)									
15-year life	16.39	18.15	19.55	7.78	8.65	9.54	5.79	6.52	7.24
20-year life	16.49	18.28	19.68	7.73	8.62	9.52	5.74	6.48	7.21

Exhibit 5-15
Flue Gas Desulfurization Economics



500-MWe plant, 30-yr levelized costs, allowance value of $300/ton

Incremental cases:

A—Conventional FGD (EPRI model)

B—AFGD, own-and-operate arrangement

C—Adds gypsum sales

D—Adds emission allowance credits at $300/ton, for 90% SO_2 removal

E—Increases SO_2 removal to 95%

References

- *Advanced Flue Gas Desulfurization (AFGD) Demonstration Project. Final Technical Report, Vol. II: Project Performance and Economics.* Pure Air on the Lake, L.P. April 1996. (Available from NTIS as DE96050313.)
- *Advanced Flue Gas Desulfurization Project: Public Design Report.* Pure Air on the Lake, L.P. March 1990.
- *Summary of Air Toxics Emissions Testing at Sixteen Utility Power Plants*. Prepared by Burns and Roe Services Corporation for U.S. Department of Energy, Pittsburgh Energy Technology Center. July 1996.

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

Project completed.

Participant

Southern Company Services, Inc.

Additional Team Members

Georgia Power Company—host
Electric Power Research Institute—cofunder
Radian Corporation—environmental and analytical consultant
Ershigs, Inc.—fiberglass fabricator
Composite Construction and Equipment—fiberglass sustainment consultant
Acentech—flow modeling consultant
Ardaman—gypsum stacking consultant
University of Georgia Research Foundation—by-product utilization studies consultant

Location

Newnan, Coweta County, GA (Georgia Power Company's Plant Yates, Unit No. 1)

Technology

Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process

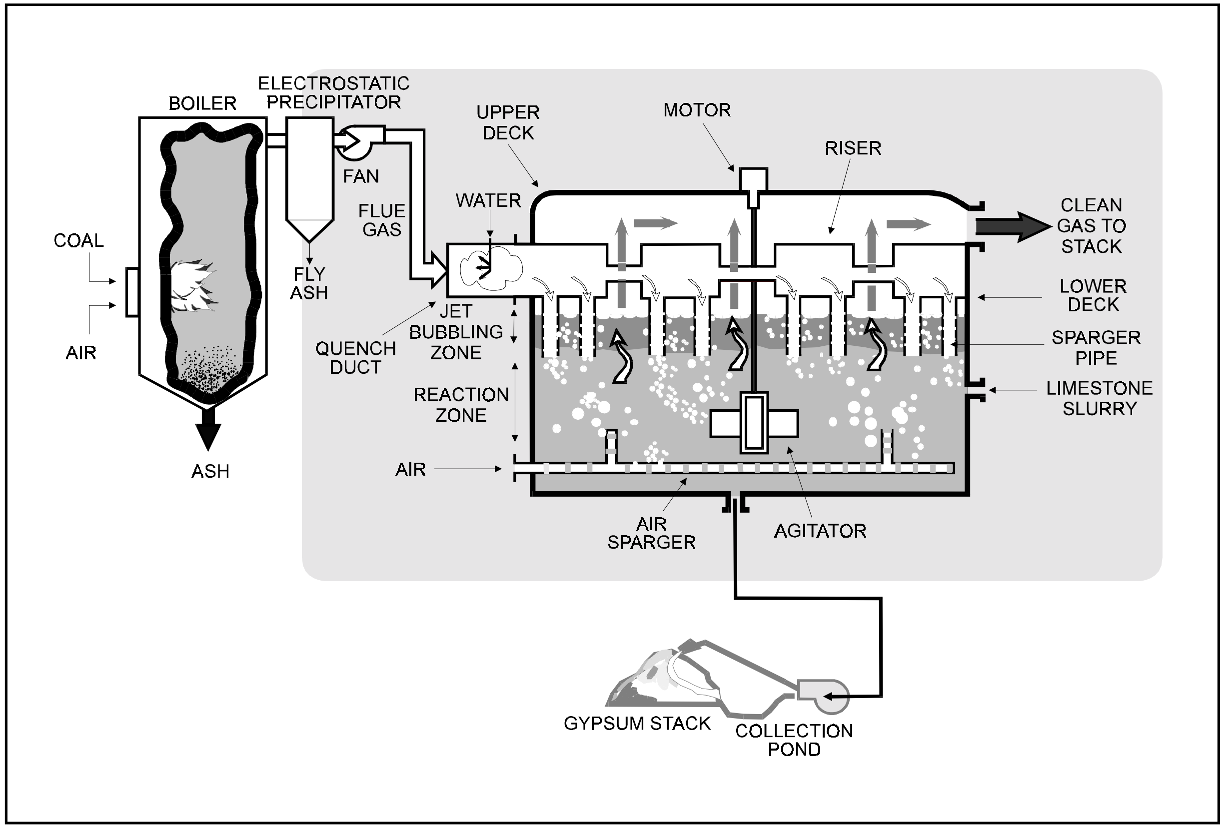
Plant Capacity/Production

100-MWe

Coal

Illinois No. 5 % No. 6 blend, 2.4% sulfur
Compliance, 1.2% sulfur

Jet Bubbling Reactor is a registered trademark of the Chiyoda Corp.



Project Funding

Total project cost	$43,074,996	100%
DOE	21,085,211	49
Participant	21,989,785	51

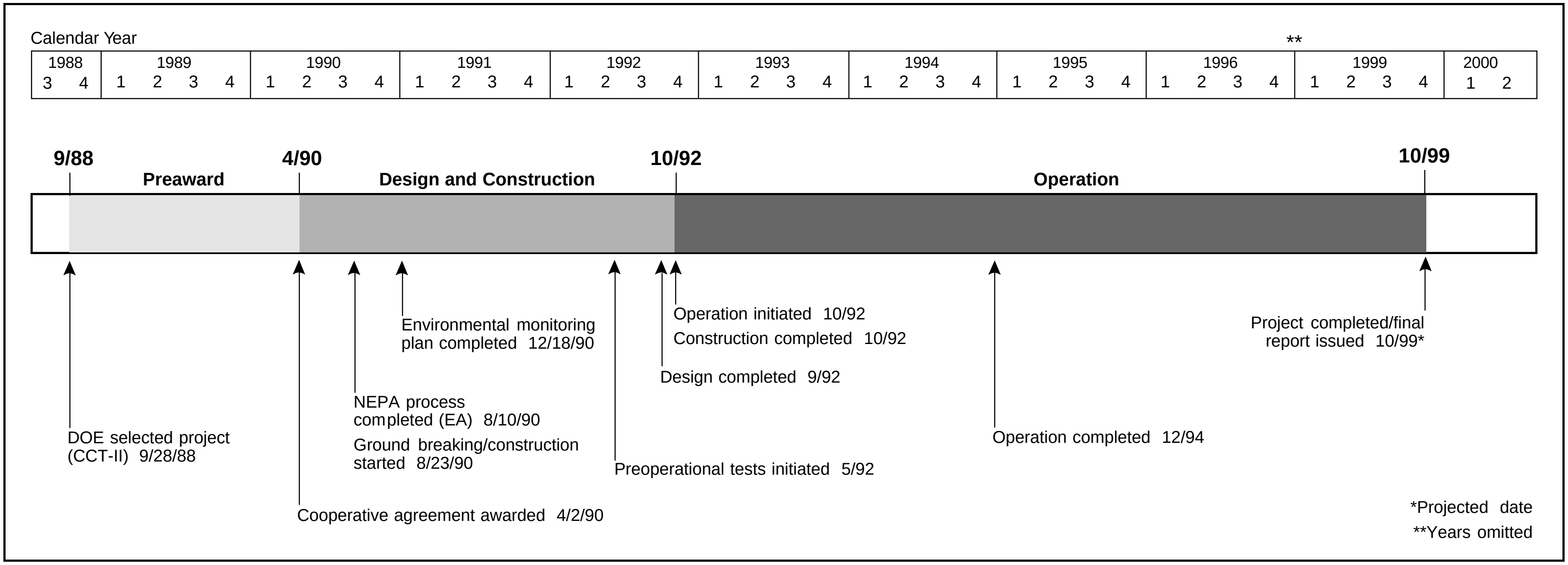
Project Objective

To demonstrate 90% SO_2 control at high reliability with and without simultaneous particulate control; to evaluate use of fiberglass-reinforced plastic (FRP) vessels to eliminate flue gas reheat and spare absorber modules;
and to evaluate use of gypsum to reduce waste management costs.

Technology/Project Description

The project demonstrated the CT-121 FGD process, which uses a unique absorber design known as the Jet Bubbling Reactor® (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics.

The flue gas enters underneath the scrubbing solution in the JBR. The SO_2 in the flue gas is absorbed and forms calcium sulfite ($CaSO_3$). Air is bubbled into the bottom of the solution to oxidize the calcium sulfite to form gypsum. The slurry is dewatered in a gypsum stack, which involves filling a diked area with gypsum slurry. Gypsum solids settle in the diked area by gravity, and clear water flows to a retention pond. The clear water from the pond is returned to the process.



Results Summary

Environmental

- Over 90% SO_2 removal efficiency was achieved at SO_2 inlet concentrations of 1,000–3,500 ppm with limestone utilization over 97%.
- JBR achieved particulate removal efficiencies of 97.7–99.3% for inlet mass loadings of 0.303–1.392 lb/10^6 Btu over a load range of 50–100-MWe.
- Capture efficiency was a function of particle size:
  - >10 microns—99% capture
  - 1–10 microns—90% capture
  - 0.5–1 micron—negligible capture
  - <0.5 micron—90% capture
- Hazardous air pollutant (HAP) testing showed greater than 95% capture of hydrogen chloride (HCl) and hydrogen fluoride (HF) gases, 80–98% capture of most trace metals, less than 50% capture of mercury and cadmium, and less than 70% capture of selenium.
- Gypsum stacking proved effective for producing wallboard/cement-grade gypsum.

Operational

- FRP-fabricated equipment proved durable both structurally and chemically, eliminating the need for a flue gas prescrubber and reheat.
- FRP construction combined with simplicity of design resulted in 97% availability at low ash loadings and 95% at high ash loadings, precluding the need for a spare reactor module.
- Simultaneous SO_2 and particulate control were achieved at flyash loadings reflective of an electrostatic (ESP) with marginal performance.

Economic

- Final results are not yet available. However, elimination of the need for flue gas prescrubbing, reheat, and spare module requirement should result in capital requirements far below those of contemporary conventional FGD systems.

Project Summary

The CT-121 process differs from the more common spray tower type of flue gas desulfurization systems in that a single process vessel is used in place of the usual spray tower/reaction tank/thickener arrangement. Pumping of reacted slurry to a gypsum transfer tank is intermittent. This allows crystal growth to proceed essentially uninterrupted resulting in large, easily dewatered gypsum crystals (conventional systems employ large centrifugal pumps to move reacted slurry causing crystal attrition and secondary nucleation).

The demonstration spanned 27 months, including startup and shakedown, during which approximately 19,000 hours were logged. Exhibit 5-16 summarizes operating statistics. Elevated particulate loading included a short test with the electrostatic precipitator (ESP) completely deenergized, but the long-term testing was conducted with the ESP partially deenergized to simulate a more realistic scenario, *i.e.*, a CT-121 retrofit to a boiler with a marginally performing particulate collection device. The SO_2 removal efficiency was measured under five different inlet concentrations with coals averaging 2.4% sulfur and ranging from 1.2– 4.3% sulfur (as burned).

Operating Performance

Use of FRP construction proved very successful. Because their large size precluded shipment, the JBR and limestone slurry storage tanks were constructed on site. Except for some erosion experienced at the JBR inlet transition duct, the FRP-fabricated equipment proved to be durable both structurally and chemically. Because of the high corrosion resistance, the need for a flue gas prescrubber to remove chlorides was eliminated. Similarly, the FRP-constructed chimney proved resistant to the corrosive condensates in wet flue gas, precluding the need for flue gas reheat.

Availability of the CT-121 scrubber during the low ash test phase was 97%. Availability dropped to 95% under the elevated ash-loading conditions due largely to sparger tube plugging problems precipitated by flyash agglomeration on the sparger tube walls during high ash loading when the ESP was deenergized. The high reliability demonstrated verified that a spare JBR is not required in a commercial design offering.

Exhibit 5-16
Operation of CT-121 Scrubber

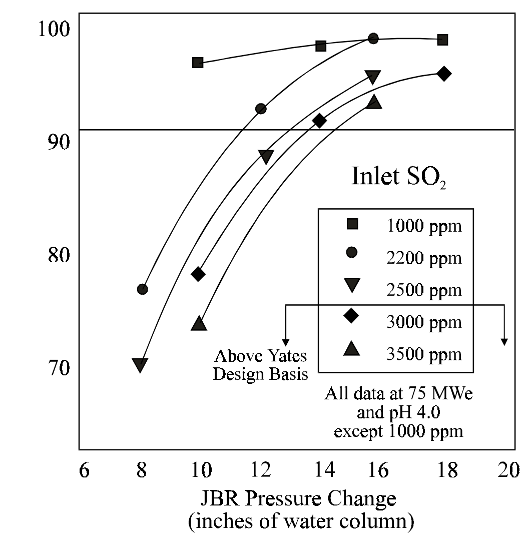
	Low Ash Phase	Elevated Ash Phase	Cumulative for Project
Total test period (hr)	11,750	7,250	19,000
Scrubber available (hr)	11,430	6,310	18,340
Scrubber operating (hr)	8,600	5,210	13,810
Scrubber called upon (hr)	8,800	5,490	14,290
Reliability[a]	0.98	0.95	0.96
Availability[b]	0.97	0.95	0.97
Utilization[c]	0.73	0.72	0.75

[a] Reliability = hours scrubber operated divided by the hours called upon to operate
[b] Availability = hours scrubber available divided by the total hours in the period
[c] Utilization = hours scrubber operated divided by the total hours in the period

Environmental Performance

Exhibit 5-17 shows SO_2 removal efficiency as a function of pressure drop across the JBR for five different inlet concentrations. The greater the pressure drop, the greater the depth of slurry traversed by the flue gas. As the SO_2 concentration increased, removal efficiency decreased, but adjustments in JBR fluid level could maintain the efficiency above 90% and, at lower SO_2 concentration levels, above 98%. Limestone utilization remained above 97% throughout the demonstration. Long-term particulate capture performance was tested with a partially deenergized ESP (approximately 90% efficiency), and is summarized in Exhibit 5-18.

Exhibit 5-17
SO_2 Removal Efficiency



Analysis indicated that a large percentage of the outlet particulate matter is sulfate, likely a result of acid mist and gypsum carryover. This reduces the estimate of ash mass loading at the outlet to approximately 70% of the measured outlet particulates.

For particulate sizes greater than 10 microns, capture efficiency was consistently greater than 99%. In the 1–10 micron range, capture efficiency was over 90%. Between 0.5 and 1 micron, the particulate removal dropped at times to negligible values possibly due to acid mist carryover entraining particulates in this size range. Below 0.5 micron, the capture efficiency increased to over 90%. Calculated air toxics removals across the CT-121 JBR,

Exhibit 5-18

Particulate Capture Performance

(ESP Marginally Operating)

JBR Pressure Change (inches of water column)	Boiler Load (MWe)	Inlet Mass Loading (lb/10^6 Btu)	Outlet Mass Loading* (lb/10^6 Btu)	Removal Efficiency (%)
18	100	1.288	0.02	97.7
10	100	1.392	0.010	99.3
18	50	0.325	0.005	98.5
10	50	0.303	0.006	98.0

*Federal NSPS is 0.03 lb/10^6 Btu for units constructed after September 18, 1978. Plant Yates permit limit is 0.24 lb/10^6 Btu as an existing unit.

based on the measurements taken during the demonstration, are shown in Exhibit 5-19.

As to solids handling, the gypsum stacking method proved effective in the long term. Although chloride content was initially high in the stack due to the closed loop nature of the process (with concentrations often exceeding 35,000 ppm), a year later the chloride concentration in the gypsum dropped to less than 50 ppm, suitable for wallboard and cement applications. The reduction in chloride content was attributed to rainwater washing the stack.

Economic Performance

Although the final economic analyses are not yet available, it appears as though CT-121 technology offers significant economic advantages. FRP construction eliminates the need for prescrubbing and reheating flue gas. High system availability eliminates the need for a spare absorber module. Particulate removal capability precludes the need for expensive (capital-intensive) ESP upgrades to meet increasingly tough environmental regulations.

Commercial Applications

Involvement of Southern Company (which owns Southern Company Services, Inc.), with more than 20,000 MWe of coal-fired generating capacity, is expected to enhance confidence in the CT-121 process among other large high-sulfur coal boiler users. This process will be applicable to 370,000-MWe of new and existing generating capacity by the year 2010. A 90% reduction in SO_2 emissions from only the retrofit portion of this capacity represents more than 10,500,000 tons/yr of potential SO_2 control.

Plant Yates continues to operate with the CT-121 scrubber as an integral part of the site's CAAA compliance strategy. Since the CCT Program demonstration, over 8,200 MWe equivalent of CT-121 FGD capacity has been sold to 16 customers in seven countries.

The project received *Power* magazine's 1994 Powerplant Award. Other awards include the Society of Plastics Industries' 1995 Design Award for the mist eliminator, the Georgia Chapter of the Air and Waste Management Association's 1994 Outstanding Achievement Award, and the Georgia Chamber of Commerce's 1993 Environmental Award.

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- *Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Innovative Applications of Technology for the CT-121 FGD Process.* Southern Company Services, Inc. Report No. DOE/FE-0158. U.S. Department of Energy. February 1990. (Available from NTIS as DE9008110.)

Exhibit 5-19

CT-121 Air Toxics Removal

(JBR Components Only)